NATURAL GAS AS AN ELECTRICITY SUPPLY OPTION

Prepared for the
Ontario Ministry of Energy
By

Blue Apple Consulting Inc.
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Ministry
of
Energy
Ontario

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PREFACE

The supply of secure electric power is vital to Ontario. The mandate to deliver electric power at the lowest feasible cost over the long term belongs to Ontario Hydro. The Corporation is engaged in an intensive review of electricity demand and supply options and system planning stretching to the year 2005. A draft Resource Development Strategy is expected in late 1987. The Corporation's power supply plans are subject to public review, through the Legislature and its Select Committee on Energy, the Ministry of Energy and other forums. Public review helps ensure that Ontario Hydro develops its long-range electric-power plans in a manner which reflects the province's overall energy requirements, and best balances energy supply security, flexibility, costs and environmental impacts.

The Ministry of Energy is responsible for giving Ontario Hydro a policy framework for planning the electricity system. This study is a contribution to the Ministry's evaluation of the province's electricity demand and supply options. Electricity options include upgrading existing facilities, building new facilities, encouraging conservation, load management, importing power, and investing in new coal and alternative technologies. Supply options using natural gas as a fuel are also a possibility. Recent developments in North American natural gas markets--in particular deregulation--have driven down the price and produced a buyer's market.

The Ministry has commissioned studies relevant to the "gas option", including papers on coal technologies, uncontracted natural gas reserves and the potential for cogeneration. These three studies, along with Ontario Hydro's Demand/Supply Options Study (Phase 1 DSOS) and 1986 BES Resource Plan 1986-2005 provided a core of information for the review of the natural gas option. Additional factual and anecdotal information was obtained through interviews with Hydro, the

Ministry of Energy and the natural gas industry. The issue is complex. The time frame allowed for this study has not permitted in-depth review of the options. Instead, we have focused on providing a framework within which to address the alternatives and a perspective on the policy and strategic issues.

We wish to thank the various organizations which contributed to this study, including the Ontario Ministry of Energy, Ontario Hydro, the Ontario Natural Gas Association and its member gas pipeline and distribution companies.

June, 1987.

UNITS OF MEASUREMENT AND CONVERSION FACTORS

1 joule (J)	= 0.000948 Btu	1 kW = 1000 W
1 kJ	= .948 Btu	1 kWh = 1000 Wxh
1 MJ	= 948 Btu	1 MW = 1000 kW
1 GJ	= 948 thousand Btu	1 MWh = 1000 kWxh
1 TJ	= 948 million Btu	1 GW = 1000 MW
1 PJ	= 948 billion Btu	1 GWh = 1000 MWxh
1 EJ	= 948 trillion Btu	1 TW = 1000 GW
		1 TWh = 1000 GWxh

Conversions:*

Natural Gas

1 cubic metre = 35.301 cubic feet

Gross energy content factor, Alberta domestic, 38.8 MJ/m^3
1.099 MJ/cf

Electricity

Primary	10.5 MJ/kWh
Secondary	3.6 MJ/kWh

Conversion

Primary	3.70 kWh/m^3; .105 kWh/cf
Secondary	10.78 kWh/m^3; .305 kWh/cf

Example of primary energy conversion:

mmcf = 105,000 kWh
bcf = 105,000 MWh
A 220-230 MW natural gas fueled generating station would need approximately 50 mmcf of gas per day, or 18.250 bcf per annum.

* Conversions are illustrative. Actual natural gas/electricity energy and cost conversions will vary with each individual situation, including energy content of the natural gas supply, transportation distances, and burning and generation technologies and efficiencies.

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EXECUTIVE OVERVIEW

A. PRINCIPAL FINDINGS

The principal findings of this report are as follows:

- Ontario's demand for electricity will rise over the long term and new demand/supply options will be required;

- coal-fired generation will increase, acid-gas emissions will rise, and new clean-burn technologies will have to be developed, if coal continues to be used as a source of power over the long term;

- delays in technological development, in obtaining approvals for new electrical system capacity, and/or in negotiating power purchase deals could threaten Ontario's electric-power supply and economic growth;

- natural gas could play a strategic bridging role, thus reducing vulnerability to disruption in electricity supply;

- changing conditions in the natural gas market have improved dramatically the competitive position of gas, at least for the short term and possibly for the longer term.

- short-, medium and long-term options are available for the use of natural gas in the production of electricity which are economic and of strategic advantage to Ontario and Canada;

- significant barriers exist to the exploitation of these options which must be addressed;

- o current favourable gas market conditions are critical to the viability of some of the options. There is some urgency to in-depth governmental and commercial evaluation and development of the options; and,

- o clarification of Government policy with respect to the use of natural gas to produce electricity is required, as also is a program review.

In the context of Canadian fuels, Ontario has a number of choices for fueling electric power generation, including nuclear, hydraulic, fossil fuels and purchases of power from other provinces. The province is exploring all options, including natural gas. To see greater use in electricity generation in Ontario, gas must be cost effective and able to contribute to the province's energy security. We believe there are situations were natural gas could be competitive with the alternatives. The time is now ripe to take a hard look at the options and not be bound by previous analysis or opinion.

B. STRATEGIC ISSUES TO BE CONSIDERED IN EVALUATING A ROLE FOR NATURAL GAS IN ELECTRICITY GENERATION

Many questions arise in the consideration of the "gas option". Among the most important are:

- o is the cost and security of Ontario's electricity supply vulnerable to lags in development of clean-coal technologies and delays in approvals for alternative supply options?

- natural gas is an "imported" energy resource. Is it to have free competitive access to the Ontario market in substantial volumes for purposes of generating electricity?
- if substantial, long term gas volumes were to be required for electricity production, what would be the implications for the "reserve test" and for gas exports, and what might be the attitude of Western producers and the Alberta government?
- would gas producers and the Government of Alberta be concerned that Ontario could lock up substantial incremental future supplies at prices lower than what might be available in the export market?
- if Ontario were in the future to argue for control of the domestic gas price would Alberta react by withholding removal permits and jeopardize Ontario's electricity production?
- how might the West react if western gas is substituted for western coal?
- should economic gas-fired parallel generation be more aggressively encouraged and, if so, what roles, should Hydro, the municipal electric utilities, the Government, the Ontario Energy Board and others play?
- is there economic/political value to reducing acid-gas emissions even further below legislated limits?

Expectations are that by the year 2000, coal burns at Ontario Hydro stations could reach 37 TW.h, approximately equal to the highest coal burn experienced in the early 1980s. Moreover, if electricity demand increases faster than forecast, coal burn could soar to 60 TW.h by the year 2000. While considerable coal-fired capacity is currently mothballed, there is a possibility that all existing coal-fired plants will be called into action to meet base load, not just peak demands. In Hydro's "Consistent Energy Set" (CES) short-term forecasts of system operations, the volume of coal use forecast for the 1987-91 period increased by 9 per cent from CES 86-1 to CES 87-2 Revised.

New coal-fired capacity may also be required because:

- trends in electricity demand are such that by the year 2005 or sooner, Ontario will probably need additional electric power generating capacity;
- most large-scale hydraulic power capacity is already well developed ;
- the capital requirements for nuclear stations are huge, public support for new nuclear stations is uncertain and the construction lead times very long; and,
- interprovincial cooperation in developing provincial electricity systems to mutual advantage is uncertain.

Thus, additional fossil-fired capacity may well have to be added. Coal reserves are plentiful, but supplies have to be imported into the province. Coal options have relatively high capital costs, long lead times and require the development of new clean-burn technologies to meet legislated acid-gas emission limits. A new Regulation has removed the emission 'banking' provision.

Coal-fired generation will eventually be constrained by acid-gas emission limits. Investment in scrubbers or equivalent technologies will be required. The costs and lead times for clean-coal technologies are substantial. Promising technologies are being explored and tested and there is optimism that advances will allow increased coal burns over the long-term. It is very much in Ontario's interest that such technologies succeed and be ready for deployment as needed, for balance within the overall electricity supply system, for fuel-supply security, and as an alternative to nuclear.

C. THE POTENTIAL STRATEGIC ADVANTAGES OF NATURAL GAS USE IN PRODUCING ELECTRICITY NEED EVALUATION

Another option to increase electricity supply is the use of natural gas-fueled generation. Recent developments in natural gas markets have created market conditions where gas can be competitive with other long-term supply options. Gas-fired generation could be utilized either by Ontario Hydro or by private power generators (parallel generation). Gas options have relatively low capital costs and comparatively short lead times. Key issues are availability and price.

Canadian gas reserves are adequate through the year 2000 and pipeline capacity can be expanded incrementally. Current prices of natural gas are competitive with coal and long-term contractual arrangements are possible. A range of purchase options for major industrial gas users are also available, from short-term buys at spot market prices to exploration and development of own gas supplies with prices hedged over the longer term.

It is uncertain how long the current buyer's market in natural gas (low spot prices for gas, or costs of land for exploration and development or costs of uncontracted reserves) will last, perhaps two to three years. The evaluation of gas options thus has some urgency to it.

Ontario Hydro has, up to now, considered natural gas to be principally a high-priced premium fuel suitable for short-duration peaking only. Hydro's Supply/ Demand Options Study, which examines alternatives over the 1990-2005 period, uses assumptions based on pre-deregulation gas markets. Moreover, the major players in the Ontario natural gas industry have been preoccupied with the challenges presented by deregulation and are themselves only now beginning to examine the opportunities for gas in electricity generation. Except in a few cases, private industry is probably unaware of the new options which are potentially available. It is time for both sides to review in depth the options for using gas in generating electric power. It has been suggested by a respected source that, as a result of Chernobyl, the potential for using natural gas in electricity generation in both centralized and decentralized facilities will be examined much more closely in the future.(1)

D. OPTIONS FOR USING NATURAL GAS IN THE PRODUCTION OF ELECTRICITY

Options are examined in this study in two categories, technical and economic.

D.1. THE TECHNICAL OPTIONS

The *technical* options available are:

- o new combined-cycle powerplants. These plants have short lead times and costs can be competitive if gas supply is contracted for on a longer-term basis. The plants offer a clean, efficient and reliable source of electric power. They can also be modular in design and be either expanded or mothballed incrementally to meet changing power needs. They reduce some of the cost risks associated with major power construction projects. Moreover, they can be run privately or by Hydro.

- o repowering with natural gas, for existing fossil-fired capacity. As generating equipment ages, efficiency and reliability are reduced. Combined-cycle repowering can take three forms: (i) peaking turbine repowering; heat recovery repowering; and, (iii) boiler repowering. Estimates suggest the cost of producing electricity in repowered plants are approximately 60 per cent of the cost of new plant i.e. 3.7-3.9 cents/kWh compared with 6.2 cents/kWh.(2)

- o select use of gas, for existing and new generating units. The two main forms of select use are the co-firing of gas with coal and seasonal use of gas to control acid-gas emissions. In these uses, gas can enhance boiler performance, lower maintenance costs and cut breakdowns. Co-firing with gas also can provide cleaner and quicker startups and insurance against disruption of coal supplies and tightening of emission controls. American experience suggests that sulphur emissions can be reduced at a cost of less than $100-$600 per ton removed on a regional basis, compared with scrubbing costs of over $3,000 per ton.(3)

- o cogeneration. Interest in this area is increasing and the potential is high. American experience indicates that gas-fired cogeneration systems are competitive with conventional coal systems, and reduce substantially air pollutants e.g. a natural gas-fueled turbine unit emits only 6%, 10% and 28% of the sulfur oxides, particulate matter and nitrogen oxides produced by coal. U.S. cogeneration costs for 1988 are estimated in the range 4.1-5.9 cents/kWh.(4)

The particular application of these technologies will vary site-by-site and with overall electric power requirements, which also vary by region in the province.

D.2. THE ECONOMIC OPTIONS

The scope of this study did not allow for the detailed analysis of the economics of the various natural gas options. We wish we could have provided this information. Nevertheless, based on information provided by the Ministry of Energy, Ontario Hydro and the natural gas industry, natural gas appears to make strategic sense as an electricity-generation option because it can:

- o increase flexibility to respond to changing generation requirements;
- o reduce acid-gas emissions;
- o improve the diversity of fuels supply;
- o decentralize electricity supply and enhance energy security; and,
- o reduce costs and uncertainty.

The evidence suggests natural gas can help, in a cost-effective way, to meet electricity demand while other more complex and uncertain electricity demand/supply options--many of which have long lead times--are being explored and developed. It could do so through direct use by Ontario Hydro and through parallel generation by private operators. Ultimately, the viability and the costs of the gas options will have to be determined in the market place.

The economics of use of natural gas can be examined for the short, medium and long terms. The boundaries between the time periods are not precise, reflecting complex and often interrelating factors. Our choice of time frames appears to us to be useful for strategic evaluation of the options and for forward planning, and best reflect discussions with interested parties. Readers may choose to apply their own criteria.

Short-term Economic Options (1987-1990)

The economic options for using natural gas over the shorter term are limited by a number of factors, the most important of which are: (i) expectations of low fossil-fired capacity needs by Hydro; (ii) the peak-load role of fossil-fired stations and their planned utilization within the total Hydro system; (iii) costs of conversion and/or demothballing; (vi) the need to keep acid-gas emissions well within prescribed limits; and (v) contractual requirements to take coal. Nevertheless, natural gas could come on stream in a short timeframe in the following applications:

(i) the demothballing and firing of the R.J. Hearn station on natural gas.; and,

(ii) parallel generation to establish a base while gas markets are favourable and any buy-back incentives can be kept to a minimum.

Use of Natural Gas at the R.J. Hearn Station.

The Hearn station is the only plant in the Hydro network which has gas-fired capacity currently--8 units with a total output of 1180 MW. Volume gas is presently available to the Ontario market in the $2.50-$2.70 per mcf range.(5) With these prices, use of gas at the Hearn station could, under certain circumstances, be economic and on stream within a year. The costs of placing Hearn back in service are estimated at $8 million.(6) A 10 bcf purchase of off-peak natural gas could displace western Canadian coal if the value of reduced acid-gas emissions is taken into account. A price lower than $2.00/mmBtu would economically displace U.S. coal if the value of reduced acid-gas emissions is recognized, and $1.50/mmBtu otherwise.(7) Ontario Hydro emissions will, in fact, be well within legislated limits in the short term; however, emission reductions below Hydro's planned levels may have economic and political value to Hydro and to the Government.

Reactivation of the Hearn station on gas could improve the security of the electrical system in the Toronto downtown core: there are difficulties involved in expanding the regional power distribution system to provide this heavy-load area with more power. Moreover, to the extent that gas could be used to generate electricity in off-peak periods, economic benefits may also be experienced by the local gas utility which could be reflected in the negotiated gas price (the utility has not put a dollar value on these benefits and they are not reflected in the above numbers).

Before Hearn could be gas-fired, however, a number of questions have to be addressed, including: penalties on coal contracts; the low efficiency of Hearn and the displacement effect at Lambton and Nanticoke; potential transmission limitations in southwestern Ontario; the condition of the Hearn plant and whether or not value is to be placed on reducing acid-gas emissions even further below legislated limits. Moreover, political issues could arise if western Canadian coal was displaced by western Canadian natural gas.

Depending upon the answers to these questions, the breakeven gas prices quoted above may have to be reduced. It should be noted that the Hearn plant has been mothballed since 1983 and some sources suggested there is a high probability it has been "cannibalized" for parts, as Hydro has refurbished other parts of its system. If this is indeed the case, then the flexibility to deploy all or part of the Hearn plant on relatively short notice to meet local system needs may be unduly constrained.

Parallel Generation Opportunities.

The potential exists for up to 3,800 MW of economic parallel generation in Ontario by the year 2000.(8) The degree to which this potential is exploited will depend on how effectively institutional, financial and informational barriers to parallel generation can be overcome.

There are a number of parallel generation projects under review in Ontario which demonstrate that opportunities exist in the short term. Examples include large-scale combined-cycle and co-generation plants in Northwestern Ontario and a combined cycle plant to serve the R.J. Hearn station, projects which would be supported by long-term gas contracts and be economic at buy-back rates close to those available presently. Smaller scale co-generation projects are also being proposed. Investment costs can be typically recovered in 1-6 years at existing buy-back rates and market prices for natural gas. A number of projects could be on stream in the 1 to 3 year short-term timeframe.

Parallel generation could improve overall electricity supply security by diversifying fuel supply, decentralizing electric power production, reducing acid-gas emissions and enhancing the flexibility of the electric power system. Incremental demand for natural gas would help support the western Canadian economy. Lower power costs for Ontario industry would improve competitiveness.

It is important to note that long-term gas supply through purchase contracts or ownership of reserves is a vital ingredient if co-generation projects are to flourish.

MEDIUM-TERM ECONOMIC OPTIONS (1990-1995)

Looking to the medium term, more options are open. Coal burns at Ontario Hydro stations will be on a rising trend over the period and acid-gas emissions will rise, although Hydro's full nuclear commitment comes on stream and coal burns are at their lowest levels in some of these years. Coal is the "swing" fuel in the Hydro system, thus, any differences between actual and forecast values of the availability of other generating technologies or of electricity demand is reflected in the demand for coal (for example, Ontario

Hydro reports that primary energy demand increased considerably in CES 87-2 Revised compared with CES 86-1). As electricity demand moves beyond Hydro's "most probable" scenario, acid-gas emissions become a constraining factor on capacity. However, flexibility to reduce coal purchases increases.

In this context, an alternative available to Hydro is *dual gas/coal firing*. This technology provides the flexibility to use gas in existing fossil-fired facilities for ignition, warmup, true co-firing and select use.

Gas purchase options for major industrial users could permit the negotiation of contracts which bring gas supplies on stream in, say 3-5 years time, yet take advantage of current attractive economics. For example, an oil and gas exploration program undertaken by users--either individually or jointly--could, if successful, produce gas supply over the longer term at hedged prices. One estimate is that such a program could yield a base price in the low $2.00/mmBtu range under current market conditions.(9) Another option is the purchase of uncontracted reserves.

Parallel generation also has considerable economic potential over the medium term. Dedicated combined-cycle plants, either Hydro owned or private-sector owned and operated are an economic, medium-term option. The strategic and other advantages of parallel generation noted previously for the short term would be greater over the medium term.

The Ministry of Energy is forecasting no real increase in F.O.B. Toronto natural gas prices over the medium term. Existing pipeline capacity can be expanded incrementally to support increased demand.

World energy markets are, of course, difficult to predict and North American natural gas markets are in a state of flux under the push and pull of market and political forces. Under these circumstances, there is considerable uncertainty for the players in the market place, and some reluctance to make predictions or talk firm prices outside of direct buyer/seller negotiations. While this reality limits the amount of market information we are able to present in this study, it does not affect the study's findings or recommendations.

LONGER-TERM ECONOMIC OPTIONS (1995 Onwards)

For the longer-term, the economics of natural gas in electricity generation are less clear. Natural gas supply could run into constraints over the long haul and real price increases could occur. However, gas purchase options offer considerable scope to tie down supplies for 20 year terms and perhaps longer.(10) Taking longer-term electricity requirements into account and the risks associated with demand/supply options, natural gas could be a more competitive fuel than thought previously and play an important role in bridging technology gaps and/or

There may be concern about whether or not natural gas supply will be sufficient beyond the year 2000 to justify long-term options and about pipeline capacity. In particular, large exports could reduce the availability of gas domestically.(12) However, at any point when decisions are being taken about alternatives the market can be tested for gas volumes, prices, purchase options and the implications for transmission. This assumption may be valid only in a deregulated market.

E. SIGNIFICANT BARRIERS EXIST TO THE USE OF NATURAL GAS IN THE PRODUCTION OF ELECTRICITY

There are a number of barriers to the use of natural gas in electricity generation. Some, such as penalties under coal contracts and others noted above will be either reduced or eliminated by the passage of time. However, other barriers exist which have to be addressed immediately if the potential for wider use of natural gas in producing electric power is to be explored fully, namely:

- Ontario Hydro's perception of its corporate economic responsibilities and the economic role for natural gas;
- lack of information and communications between natural gas suppliers and users on the opportunities for using this fuel;
- insufficient appreciation of the facts on the availability of natural gas and options for purchase; and,
- the incomprehensibility of Hydro's "standard cost" pricing and ranking of supply/demand options.

What is needed are clear policies corporately in Ontario Hydro and in the Government stating the role and setting the parameters for natural gas in the generation of electricity in Ontario over the long term.

F. POLICY IMPLICATIONS

There are three broad policy options for the Government to consider with respect to the future role of natural gas in producing electricity:

- o the status quo;
- o an advocacy role; and,
- o a mandate role.

The status quo policy option allows Ontario Hydro to determine the extent of natural gas use for purposes of electricity generation by both itself and private generators. In reality, Hydro will anyway play an important role. The issue is whether or not Hydro should control the process.

An advocacy role for the Government would see the Ministry of Energy playing the role of broker, providing essential information and education and bringing together gas suppliers and electricity generators. A coordinating mechanism and education program would be required.

A mandate role for the Government would see the Ministry of Energy stating a positive policy with respect to natural gas usage in electricity generation and establishing explicit criteria and programs (and legislation) to overcome institutional and other barriers. Such a policy position might include a parallel-generation strategy with multi-year targets and favourable buy-back rates. A coordinating mechanism would be required.

G. CONCLUSION

There are opportunities for using natural gas to generate electricity which are both economic and environmentally beneficial. Ontario Hydro should re-examine the natural gas options, industry should investigate the possibilities and the Government of Ontario should review the policy and program options. There is some urgency to these actions if favourable gas market conditions are to be used to full advantage over the next few years.

Options for *using* gas to produce electricity in the short-term are more limited than in the longer term because of various constraints. However, in the short-term, steps can also be taken to *evaluate and negotiate* deals to put gas on stream in both the medium and long-terms.

Strategically, natural gas has the potential to bridge technology gaps and delays in obtaining approvals for alternative supply options.

It is apparent that many of the issues related to natural gas use have federal-provincial implications. For the gas options identified above to be workable, potential gas users must have confidence that federal-provincial frictions will not inhibit operation of the market place. The pre-eminent requirement is that gas should be allowed to compete on even terms in a free market.

NATURAL GAS
AS AN ELECTRICITY SUPPLY OPTION

INTRODUCTION

In assessing the potential contribution natural gas is capable of making to electricity supply a number of steps have been necessary:

(i) review of the projected demand for electricity, existing supply capacity and new system demand/ supply options;

(ii) assessment of the availability and cost of gas supplies;

(iii) identification of the potential incremental uses for natural gas in the production of electricity by Hydro and by private power producers (parallel generation);

(iv) identification of barriers to the use of gas-- economic, political and institutional;

(v) a strategic evaluation; and,

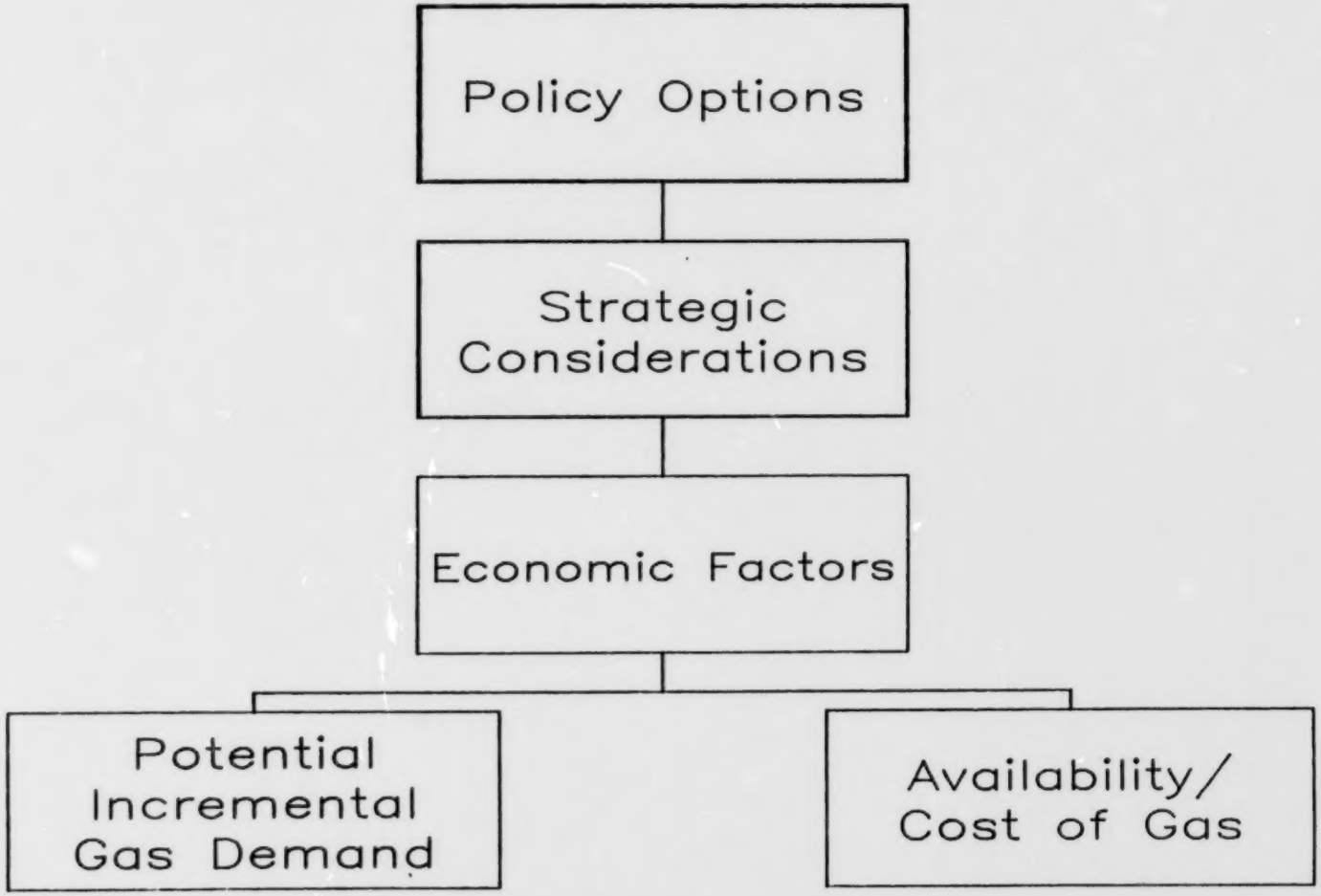
(vi) development of options.

This study begins, in Section 1, with an overview of Ontario Hydro's bulk electricity system resource plan, demand and supply options and attitude towards and plans relating to natural gas. Section 2 examines economic options for use of natural gas in the Ontario Hydro system and by private power producers in both combined-cycle and co-generation configurations. Section 3 discusses the long-term availability and cost of natural gas and options for purchase. In Section 4, the barriers which exist to the wider use of natural gas in electricity generation are identified and discussed. Section 5 lists a number of strategic issues which are important in review of the gas option, and Section 6 discusses policy implications.

To reiterate a comment in the Executive Overview, developments in world energy markets are difficult to predict and natural gas markets in North America are in in a state of flux under the play of market and political forces. Under these circumstances, hard numbers on the economics of gas options for the future may be impossible to attain, other than at the bargaining table. Nevertheless, the information and analysis provided in this study suggests quite strongly that natural gas may have strategic advantages in the production of electricity which merit close review by the Government, Ontario Hydro and other Ontario-based gas users.

Chart 1 is a tree diagram which outlines the major component elements considered in our review. More detail is provided in the charts section at the back of this paper.

Chart 1
NATURAL GAS AS AN ELECTRICITY SUPPLY OPTION



I. ELECTRICITY DEMAND, SUPPLY AND OPTIONS TO 2005

This section of the paper examines short- and long-term electricity requirements, sulphur emissions, the DSOS options and the Hydro evaluation of supply options using natural gas.

1.1. THE SHORT-TERM OUTLOOK (1987-90).

Ontario Hydro's "Consistent Energy Set 87.2 Revised" covers the planning period 1987-1992. In these projections, excess energy will be produced in each year and coal-fired energy production is reduced from previous estimates. The level of coal-fired energy production estimated for 1987 is approximately 55 per cent cent of the record high in 1984. Annual coal-fired production is projected to decline steadily to 1992; however, between CES 86-1 and CES 87-2 Revised, the projection of total coal use over the period 1987 to 1991 has been raised by 9 per cent, indicating the volatility of such projections. Chart 2 projects coal burns to the year 2005.

Table 1 shows the expected output of the various Ontario Hydro coal-fired stations over the short-term. The distribution of production changes, with Lakeview, the marginal plant on the East System, seeing a disproportionate shrinking in use (from 13 per cent of the total to less than 0.5 per cent. Lambton also contributes less to production, as its share drops from 30 per cent to 12 per cent. Nanticoke takes on a greater share of the total production and it is anticipated its share will rise from 50 per cent to 76 per cent. The lignite units in Thunder Bay and Atikokan increase their relative contribution also, because of coal "take or pay" constraints. All Hearn and Keith unit, and Thunder Bay unit 1 are assumed to be mothballed.

Table 1

EXPECTED FOSSIL OUTPUTS, 1987-1991
GW.h

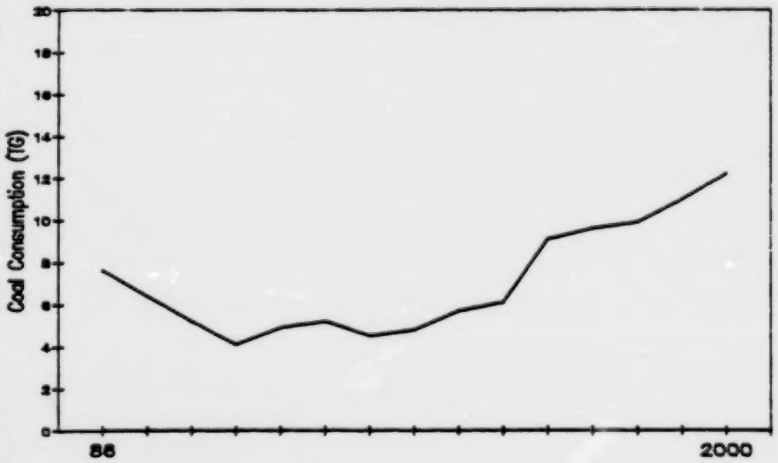
	87	88	89	90	91	92
Lakeview	588	341	227	132	65	44
Lambton	5,830	5,132	4,300	2,444	2,649	1,248
Nanticoke	13,178	11,606	10,455	9,536	8,302	8,193
Total East Coal-Fired	19,596	17,079	14,982	12,112	11,016	9,485
Thunder Bay 2,3	976	887	827	851	892	919
Thunder Bay unit 1	--	--	--	11	27	20
Atikokan	512	446	522	493	446	412
Total West Coal-Fired	1,488	1,333	1,333	1,349	1,355	1,351
CTU	13	13	13	13	13	13
Total Coal-Fired	21,097	18,425	16,344	13,480	12,394	10,849

Source: Ontario Hydro, Consistent Energy Set 87-2, Revised.

While the net electrical capability factors for the operating fossil stations are quite similar, the capacity factors forecast vary widely, as shown in Table 2. In all stations, production is heavier in the December-March period. Acid-gas emissions are forecast to remain below legislated limits.

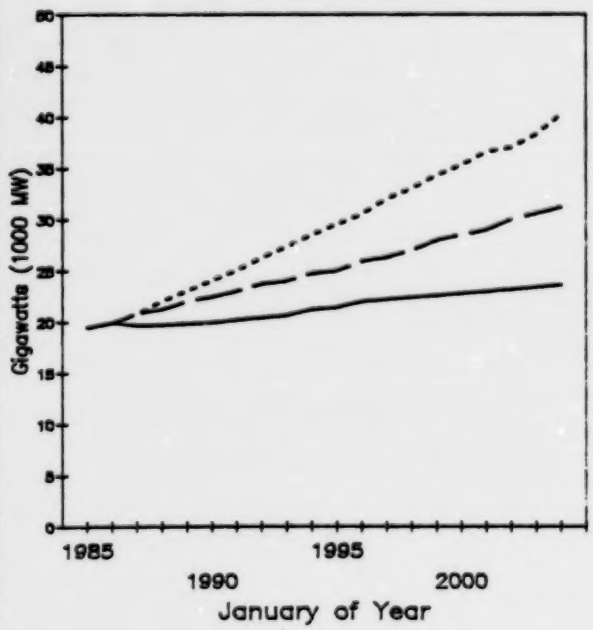
Hydro states that fossil-fired generation is "the balancing term in the equation" and that it is held to a minimum because of the relatively high cost of coal. Moreover, in the estimating procedure, the requirement to burn lignite to meet delivery and inventory constraints are met. The variability in the fossil-fired generation estimates is the sum of the variabilities of several other resources, thus Hydro acknowledges that fossil-fired generation requirements may be subject to wide swings.

Chart 2
COAL BURNS PROJECTED TO INCREASE:
ONTARIO HYDRO 1986 BES RESOURCE PLAN
1986–2000



Source: Ontario Hydro BES 1986.

Chart 3
ONTARIO HYDRO'S LOAD FORECAST:
1985–2005



LEGEND
Low Load Growth
1985 Load Forecast
Upper Load Forecast

Source: Ontario Hydro DSOS.

Table 2

COAL-FIRED STATIONS PRODUCTION
1987-92

	Net Capability		Net Capacity	
	87	92	87	92
	(percent)			
Lakeview 1-8	50	50	3	0
Lambton 1-4	76	74	34	7
Nanticoke 1-8	76	78	38	24
Thunder Bay 1	0	86	0	2
Thun. Bay 2-3	87	87	36	34
Atikokan	81	85	27	22

While the net capability of Hydro's fossil-fired plant remains relatively unchanged over the 1987-92 period, its utilization, or net capacity, is forecast to fall as additional nuclear power comes on stream.
For definitions of *net capability* and *net capacity* see "Technical Terms" at the end of this paper.
Source: see Table 1.

1.2 LONGER-TERM SYSTEM REQUIREMENTS

In addressing system supply needs to the year 2005, Ontario Hydro has developed high, low and most probable load forecasts. No additional capacity is required to meet the low-load forecast through 2005. The most probable load forecast in CES-86-1 sees annual average load growth of 2.5 per cent. (In CES 87-2 Revised, Hydro indicates that its forecast of primary energy demand has increased considerably over CES 86-1). Under this scenario, existing and committed capacity, together with certain as yet uncommitted options, are sufficient to meet system needs until the year 2000, approximately. By 2005, however, the need arises for 3,500 MW of further capacity. To meet the high-load forecast would mean adding further capacity as early as 1993 and as much as 16,600 MW of resources by 2005. The possible rehabilitation of units scheduled to be retired prior to 2005 could reduce new capacity requirements by up to 1,500 MW.

Altogether, the gap between the high and low load forecast widens to 18,400 MW by 2005, an amount equivalent to approximately two-thirds of Hydro's current system capacity. For Hydro, the wide range between the low and high load forecasts,

> *"...illustrates the need to retain flexibility in planning to meet possible future demands and to respond to a wide variety of possible conditions, particularly when shorter term need dates could eliminate options with long lead times."*(13)

Under the most-probable load forecast, by 1992, nuclear and hydraulic power would supply approximately 92 per cent of system energy requirements; however, with growing demand and the reactivation of fossil-fuelled plants, nuclear and hydraulic's combined share would drop to approximately 70 per cent by the year 2005. These projections assume that planned transmission improvements come on line.

1.3 SULPHUR EMISSIONS COULD EXCEED ALLOWABLE LIMITS

By the year 2000, coal burns could reach 37 TW.h, approximately equal to the highest coal burn experienced in the early 1980s. Furthermore, by 2002, the required coal burn exceeds limits allowable even after the installation of scrubbers or equivalents. New options would be needed. Under the high-load growth scenario, new options would be needed by the mid-90s. Coal burns under the low-load forecast would meet emission control requirements without control technology.

In the most probable forecast, the need would arise for scrubbers or their equivalent on all twelve 500MW coal-fired units. All Lambton and Nanticoke units would be fitted with scrubbers or equivalent between 1994 and 2000, although firm export orders could advance these dates. Furthermore, the high-load scenario accelerates Lambton and Nanticoke conversions to between 1992 and 1995, which Hydro suggests may not be physically feasible. Under this scenario, by the year 2000, much of the coal-fired resources on the system would be base loaded and producing 60 TW.h. while Lennox (oil/gas) would be pumping at an annual 50% capacity factor. Scrubbed units are assumed to burn 2.5 per cent sulphur coal. Unscrubbed units would be required to burn low sulphur (1% or less) coal. When the average sulphur content required in the unscrubbed coal falls below 1 per cent, costs increase significantly.

1.4 HYDRO'S EMISSION CONTROL STRATEGY

Hydro expects acid-gas controls to be permanent, with no increase allowed in annual emissions. The Corporation's emission control strategy has three basic elements:

(i) reduce coal use by increasing nuclear generation;

(ii) use lower sulphur coal and coal cleaning;
and,

(iii) install control technology e.g. low NOx burners on all Nanticoke units by 1988 and scrubbers or equivalent for existing coal-fired stations.

Hydro is not committed as yet to installing scrubbers. Alternatives being examined by the Corporation include clean-coal technologies and independent parallel power generation. Natural gas can feature in both. However, the Hydro 1986 BES Resource Plan assumes no natural gas is consumed in the generation of electricity

over the next 20 years. Hearn Units 1-5, which are gas-fired and mothballed, are not expected to be needed by Hydro under most probable load forecast assumptions.

1.5 THE DSOS OPTIONS

Ontario Hydro's installed winter capacity is shown in Table 3 for 1987 and 2005. System capacity is projected to expand from 29,554 MW currently to 33,695 MW in 2005. The contribution of nuclear grows from 9727 MW to 14,064 MW, and that of hydraulic from 6,497 MW to 7,569 MW. Coal-fired capacity falls modestly from 10,178 MW to 9,243 MW, while oil-fired capacity is maintained at 2,232 MW. Gas-fired capacity is reduced from 588 MW to zero due to retirement of plant. Independent generation put in place is projected at 330 MW.

Table 3

ONTARIO HYDRO - TOTAL SYSTEM
INSTALLED WINTER PEAK CAPACITY (MW)

Net Totals	1987	2005
Coal	10178	9243
Gas	588*	0
Oil	2232*	2232
CTUs	332*	257
Total Fossil	13330	11732
Hydroelectric	6497	7569
Nuclear	9727	14064
Independent generation	0	330
Total system	29554	33695**

Source: Ontario Hydro, 1986 Bulk Electricity System Resource Plan, 1986-2005.
*All oil and gas-fired capacity and 28 CTU capacity mothballed.
**Includes 1568 retirements offset by 1397 "uncommitted".

As Table 4 indicates, the total Hydro system surplus load-meeting capability of 4,281 MW in 1987 is forecast to become a deficit of 2,832 MW by the year 2005.

Table 4

ONTARIO HYDRO - TOTAL SYSTEM GENERATION CAPACITY AND PEAK LOADS (MW)

	1987	2005
Total Installed Generation Capacity	29554	33695
Planning Firm load	19781	30005
Load meeting capability	24062	27173
Surplus LMC	4281	-2832

Source: see Table 3.

Ontario Hydro has no approvals for new generating capacity and is examining a range of demand/supply options. In November 1985, Hydro published, "Meeting Future Energy Needs, An Initial Review of the Options",(14) followed in February, 1986 by, "Demand/Supply Options Study, The Options".(15) The Chairman of Ontario Hydro had this to say of future system planning:

> *"The prudent course then is to look at options... that will give Ontario Hydro flexibility. We must have the electrical power to meet rapid economic growth, however unexpected. But we would like to be able to meet future needs without commiting ourselves necessarily to rapid expansion."*(16)

and,

"The disadvantage of coal from Ontario's viewpoint is its high cost, the fact that it is still a chief source of pollution. Emission controls do help, but this can only partly limit damage to the environment."(17)

Table 5

ONTARIO HYDRO DSOS FOSSIL SUPPLY OPTIONS

Options Retained
For Further Study

- Coal--subcritical, supercritical
  - and IGCC
  - Conversion of Lennox
- Oil and Gas--Lennox restart
- Small Generation:
  - Cogeneration
  - Municipal solid waste
  - Small coal
  - Combined cycle/combustion turbine
- Rehabs, Conversions, Life Extensions:
  - Lakeview, Hearn, Keith & Lennox

Options Which Will Not
Be Studied Further

- Coal--lignite in the East System
  - AFB (except for rehab)
  - Single unit station
- Oil and Gas:
  - major oil-fired plant (except Lennox restart)
  - major gas-fired plant (except Lennox conversion)

Source: Ontario Hydro, Demand/Supply Options Study.

The fossil-fueled supply options evaluated in the DSOS fall into two groups: (i) those not expected to make a major contribution in the 1990-2005 timeframe; and (ii) those options retained for further study. As mentioned previously, the 1986 BES Resource Plan forecast no utilization of natural gas. Moreover, the retained DSOS options (see Table 5) provide scope to examine the contribution natural gas could make using updated market information.

It is important that the methodology, data and assumptions used in the evaluation of alternatives not discriminate unfairly for or against any particular fuel or technology. Hydro's Demand/Supply Options Study's preliminary ranking of the options aims at calculating "cost effectiveness, encompassing all costs."(18) A "standard cost" methodology is employed which estimates the cost of meeting an increment of load growth under various options and assuming the existing system operates in an optimum manner. Most options tend to have standard costs higher than the incremental system cost, and they are ranked from higher to lower.(19) The method attempts to capture the value of each option in meeting capacity and energy shortfalls. Those option with the higher standard cost tend to be looked at less favourably.

Ontario Hydro acknowledges there are problems with its standard cost methodology. As applied, it does not account for differences in the timing, reliability or flexibility of options, nor for their varying environmental, social and other impacts. Neither can it capture interaction between options, measure the effects of different amounts of each option, or the impacts over time. Moreover, the method requires all options to compete with the bulk electricity system as it is now, and not as it might look under a different configuration.

1.6 NATURAL GAS OPTIONS MERIT A NEW LOOK

Notwithstanding Hydro's caveat that efforts to date have focused on technical feasibility and long-term costs only, and that environmental, economic, public acceptance and other factors are to be addressed subsequently, the standard cost method of ranking the options and the conclusions which flow from it are in danger of being greatly overplayed. There are better options for the use of natural gas today than when the DSOS examination was conducted and a new, in-depth look at them is merited, notwithstanding the earlier DSOS results.

Hydro has assumed quite high natural gas prices in its standard cost calculations. The base case assumes a price of $23.49/mmBtu in the year 2000, or $8.19/mmBTu in 1985 dollars. This represents an annual escalation of 7.25 per cent. In a sensitivity test where gas prices escalate only at the rate of inflation from 1990 onwards, the assumed price is $15.8/mmBtu in the year 2000, or $5.88/mmBtu in 1985 dollars. Volume gas can be had today in the range of $2.70/mmBtu. This price, escalated at the 7.25 per cent escalator, would yield a year 2000 price of $7.71, less than one third of the price assumed by Hydro in its base case. Since a 32 percent reduction in the gas price lowered standard costs by 5 per cent in Hydro's analysis, it may be reasonable to assume that a two-thirds drop would lower standard costs by 10 per cent. At these lower standard costs, some gas-fired options could be competitive with coal options (with scrubbers or equivalent), perhaps even more competitive.

It is of interest also that the Ministry of Energy's projections for industrial natural gas prices (mid-case) show a base price for 1987 of $3.17 GJ, rising to $6.16 in 2000, a far cry from Hydro's $23.49. The Ministry's high-case forecast for 2000 is $8.32 GJ. Whereas in the DSOS, Hydro has assumed real price increases for natural gas over the longer-term, the recent Ministry of Energy forecast calls for flat to declining real prices. The National Energy Board's gas price projections are also considerably below those in the DSOS. Hydro's current view is that natural gas prices will be low for perhaps two years or so, but that beyond that point real price increases are still inevitable.

Table 14

SENSITIVITY OF STANDARD COSTS TO NATURAL GAS PRICE ASSUMPTIONS
(1984 $/mw.h)

	Hydro's High Gas Case	Adjusted Gas Case
Lennox 4x500 MW Coal w/s	40.4	
4x500 MW Gas	42.1	38.0
Lakeview Extn.	38.7	
Combined Cycle 2x200 MW Gas	46.7	43.5
8x200 MW Gas	46.6	43.4
Industrial CTUs 2x100 MW Gas	44.5	39.9
10x100 MW Gas	44.4	39.8

Source: Ontario Hydro.

The DSOS predicts no real increase in coal prices; however, the U.S. Electric Power Research Institute (EPRI) projects real price increases for reference coals over the 1985-2000 period. (20) How the price of coal used by Hydro will be affected as existing contracts expire is unclear. Contracted Western Canadian coal is more expensive currently than natural gas on a heat content equivalent basis i.e. $3.8 mmBtu for coal as compared with $3.00 mmBtu or less for industrial natural gas. However, the current spot price for Western Canadian coal is probably very close to the market price of natural gas.

The following section discusses options for natural gas which more appropriately reflect the economic opportunities presented by deregulated gas markets.

2. ECONOMIC OPTIONS FOR NATURAL GAS IN ELECTRICITY GENERATION

When today's economics of natural gas are taken into account and its strategic advantages considered, it is evident this fuel has potential for use in the production of electricity by private sector and public sector power producers, generating electricity for their own use and/or for sale. This section discusses first the contribution gas-fired parallel generation is capable of making, and second possible economic uses of natural gas by Ontario Hydro in its bulk power system.

2.1 PARALLEL GENERATION IN THE U.S.

Parallel generation is simply the production of electricity by private operators who produce power for their own use and/or for sale.

In the United States, parallel generation is rapidly becoming big business. The American Gas Association (AGA) estimates there are 1,250 gas-fired co-generation units in that country representing 11,000 MW of electrical capacity and an annual gas demand of 711 Bcf. [21] The Association estimates the potential for natural gas fired co-generation to be 40,000 MW of electrical capacity, or the equivalent of 2 Tcf of annual gas demand. Of the nearly 25,000 MW of co-generation capacity which has received qualified facility status from the Federal Energy Regulatory Commission (FERC) (see Table 6), 59 per cent are natural gas driven. The AGA believes gas is competitive in all ranges of kW and MW generat--ing-unit sizes. Coal is the major competition; however gas is seen to be very competitive:

"Natural gas is economically and environmentally preferable to coal for use in most large-scale industrial applications. This economic advantage exists, in spite of the generally lower fuel cost for coal relative to natural gas, because of the lower capital costs and the elimination of many non-fuel operating costs for natural gas systems."(22)

In an analysis of co-generation economics in 35 scenarios, the AGA found that gas cogeneration systems always had lower annualized costs than conventional coal systems.(23) In addition, the total air pollutants were found to be far lower with natural gas. Compared with coal, it was found that a natural gas-fueled turbine emits only 6% of the sulfur oxides, 10% of the particulate matter, and 28% of the nitrogen oxides. The AGA concludes:

"We are finally committed to the belief that cogeneration does provide a reliable and cost effective alternative to central power and can help electric utilities avoid costly nuclear and coal-fired construction projects."(24)

Cogeneration market development is being facilitated by flexible rate-making regulations. Some 20 U.S. gas distribution companies offer special rates for cogenerators because of their steady load characteristics. However, a more vital facilitator is the U.S. Public Utility Regulatory Policies Act of 1978 (PURPA).(25) This legislation authorizes FERC to remove regulatory and economic obstacles to cogeneration and electric power production by small facilities using certain renewable or alternative fuels. It also requires state agencies, for example a Department of Public Utility Control, to establish rules and rates for the interconnection of cogenerators and electric utility systems. Cogenerators must apply for certification and meet certain criteria.

Table 6

U.S. COGENERATION FACILITY FILINGS BY MW CAPACITY

1980	443
1981	878
1982	3,524
1983	3,823
1984	3,986
1985	8,635
1986	3,637
Total	24,501

Source: Federal Energy Regulatory Commission.

The key features of PURPA are:

- utilities are required to offer reasonable buy-back rates based on avoided cost;
- utilities must offer a guarantee of inter-connection and backup service;
- utilities must provide supplemental power at non-discriminatory rates;
- cogenerators are exempt from federal and state utility regulations; and,
- cogenerators using oil or natural gas must meet certain operating and efficiency standards.

PURPA has been challenged twice in the courts by utility interests, but in both instances the U.S. Supreme Court upheld it. Not all electric power utilities are against the legislation. Some, like the Connecticut Light and Power Company, have embraced cogeneration and integrated it into their system planning. A recent offer to purchase 450 MW of cogenerated power in Connecticut was filled in two months and nearly 100 per cent oversubscribed. In August 1986, the New Jersey

Board of Public Utilities ordered that Jersey Central Power & Light purchase up to 600 MW of co-generation and small power production capacity. This move followed on the heels of an offer to purchase 200 MW the year before which was quickly oversubscribed. Qualifying criteria vary from case to case.

The process of communicating with and educating energy users on cogeneration is well advanced south-of-the-border. Numerous handbooks, technical manuals and other publications are available covering most sectors of the economy. The role of the public sector is fairly well defined. U.S. developments will be of interest to Ontario; however, substantially higher U.S. prices for base-load electricity were a strong motivating factor to U.S. actions.

2.2 CO-GENERATION IN ONTARIO

In Ontario, independent generation accounts for approximately 5 per cent, or 1200 MW, of electricity production, of which 680 is hydro-electric and the remainder thermal (mostly in Sarnia and Northwestern Ontario) and fueled by coal, natural gas and industrial by-products such as spent pulping liquor. The major existing cogeneration installations include Dow Chemical and Polysar in Sarnia, 181 MW and 60 MW of capacity respectively, and Great Lakes Forest Products in Thunder Bay, 92 MW. Utilization of this capacity varies. There are a modest number of projects on the smaller (1 to 10 MW) scale in manufacturing and at two universities. Some of Ontario's cogeneration facilities have been in place for decades, others have been installed in recent years. A little more than one half of existing cogeneration capacity is fueled by natural gas.

In its DSOS, Ontario Hydro has assumed that 330 MW of additional cogeneration can be in place by the year 2000 (260 MW of industrial and commercial, 50 MW of municipal solid waste and 20 MW small scale hydro) and that favourable buy-back rates and a proactive role by Hydro could add to this figure. Today, some in Hydro speak of cogeneration potential in the 1000 MW range, and of opportunities to be found in the food and beverage industries and in large institutions such as hospitals, hotels and universities. Natural gas-fired cogeneration is expected to continue to be the major form.

A recent study of the potential for cogeneration in Ontario conducted by ACRES International Limited for the Ministry of Energy concludes that the total technically possible co-generation is almost 10,000 MW. (26) The economic potential is less, but exceeds 3,800 MW by the year 2000--1942 MW industrial, 1,321 MW residential, 459 MW commercial and 110 MW institutional. Because of various institutional, financial and information barriers, ACRES estimates that only 1,300 MW--all industrial cogeneration--will be developed unless existing barriers are removed or reduced.

The ACRES study found that almost no cogeneration projects were started in Ontario over the 1979-86 period. In the conduct of our study, we have learned that a number of new co-generation projects are at the proposal stage in Ontario. One opportunity arises where additional compression facilities (six 12 MW units) are required to facilitate 1988/89 natural gas exports. These compressors could also produce electric power for sale to Ontario Hydro. The Corporation advises that it is evaluating co-generation opportunities at two sites in the North West, each in the 50 MW range. Examples can also be found in southern Ontario where Hydro is negotiating a co-generation deal with a major food processing company and at least one natural gas utility company is developing specific cogeneration proposals. Table 7 lists some modest proposals under active consideration.

Table 7

SOME COGENERATION PROPOSALS UNDER REVIEW IN ONTARIO

Proposals:

Major Manufacturer: Displacing air compressor with a steam turbine.	Investment		$90,000
	Energy savings: (annual)		
		displaced elec.	360,032
		increased gas	-279,820
		Total annual savings	$80,012
	Years to payback 1.12		
	Note: an alternative configuration requires a much larger capital investment and payback increases to 6 years.		
Major Manufacturer: Install turbine generators to supply steam and electricity all year, with peaking capacity.			
	Investment		$545,314
	Energy Savings:		
		displaced elec.	149,438
		increased gas	-15,823
		Total annual savings	$133,615
	Years to payback 4.08		
	Note: another option has a payback of 2.82 years.		
Agricultural Operation: Use of reciprocating engine to produce heat and electricity	Investment	$200,000	
	Payback 3.6 years		

Source: Industry. Proprietary nature of data precludes further details.

The economics of cogeneration can be attractive; however, the accelerated CCA provisions (Class 34) are important. If impending tax reform were to remove these provisions, replacement incentives may be required. The complication arises in that cogeneration has a tax advantage over combined cycle in view of the latter's typically higher heat rate.

While Ontario Hydro has seen potential in co-generation, has implemented buyback rates and is currently engaged in discussions on projects, we have a number of concerns for the future of co-generation in Ontario. First, our interviews with Hydro staff leave us with the impression that corporate policy on cogeneration is not well developed within the Corporation, as indicated by differences of view among individuals and departments. We understand, however, that Hydro is in the process of firming up its policy.

Second, existing buyback rates favour renewable fuels e.g. small Hydro and industrial and municipal waste. (27) Third, while the DSOS states that buyback rates are based on long-run avoided costs this apparently is not the case. As indicated, Hydro is reviewing co-generation policy including the implications of moving to avoided costs and incentive programs. Currently, Hydro's approach to co-generation could not be described as "proactive".

The ACRES study, for instance, suggests that the greatest institutional barrier to cogeneration may be "the fully centralized position of Ontario Hydro."(28) We share with ACRES the view that the private sector is also uncomfortable with the parallel generation option, at least in part because Government policy is unclear.

As discussed previously, in the United States legislation was required to force electric utilities to include economic cogeneration in their systems. Also, cogeneration educational and informational programs were developed and imple mented. It is beyond the scope of this study to evaluate the merits and impact of U.S. legislation and pro co-generation programs.

2.3 COMBINED CYCLE IN ONTARIO

One particular technology applicable in parallel generation is "combined cycle" technology. Ontario Hydro includes this option in its DSOS, but only in the context that it is Hydro owned and operated. Not addressed by Hydro is the possibility of private sector combined-cycle operations dedicated either wholly or partly to the production of electricity for sale to Hydro and or industry. A proposal was developed to build a 50 MW stand alone combined-cycle station in North Western Ontario (as an option to an industrial cogeneration facility) to supply electricity to Hydro.[29] The project is summarized in Table 8.

Table 8

PROPOSED COMBINED-CYCLE PLANT

Project size	50-60 MW
Capital Cost	40+ $ million
Output	56920 kW
Heat rate	8196 Btu/kW.h
Power price declining	4.4cents/kW.h

Advantages claimed by proponents:
--reliable incremental power
--capacity tailored to need
--location flexible
--environmentally benign
--short construction period, 2 years
--location on TCPL pipeline minimizes gas transportation costs
--existing Hydro transmission network serves demand centres

Source: Industry. Proprietary nature of the information precludes identification of proponent.

Yet another proposal which is still in planning stages, envisages a privately owned combined-cycle plant dedicated to producing steam and electricity for the R.J. Hearn GS.

Among other things, at issue is the extent to which Hydro will accept decentralization of a modest portion of its power supply, and a diminution in its monopoly supply role. The Corporation has some legitimate concerns, for example, the reliability of private power supply to its system, a requirement (we presume) that Hydro provide backup supply in the event a private power supply fails, and that cogeneration be cost-competitive. Hydro would presumably also prefer to have substantial influence and control over the implementation of cogeneration and dedicated combined-cycle plants. These concerns, and those of industry, need to be addressed in a cogeneration policy.

2.4 NATURAL GAS OPTIONS FOR ONTARIO HYDRO

In its options review, Hydro has not considered the potential advantages of private combined-cycle plants. Neither has it evaluated in any direct way the possibility of co-firing natural gas with coal, one specific application of which is "select use" of gas to reduce sulphur emissions.

Full assessment of Hydro's gas options under the assumption that natural gas can be priced competitively and/or have significant non-price advantages, requires more information than has been provided to us. However, the following discussion gives a reasonable overview of the generic options.

Short-term Options (1987-90)

For the short term, while considerable fossil-fired capacity is mothballed, contractual commitments on coal constrain flexibility, and emission standards are being met, the best opportunity for using gas may be at Hearn or Lambton. The Hearn station has gas-fired units--the only ones in the Hydro system--which could be reactivated. It is not clear how much of the 1180 MW of gas-fired capacity could be re-fired in a short time frame, because the condition of some of the equipment is in doubt according to some observers. The units have been mothballed since 1983 and are scheduled for retirement in 1989. The cost of putting the station back in service has been estimated at $8 million. (30) Moreover, the efficiency of this station is relatively low.

Coal-fired stations are used to their capacity only in the winter months. It has been estimated that a 10 Bcf purchase of off-peak (March to November) natural gas could economically displace western Canadian coal at Hearn if the gas was priced below $2.40/mmBtu (although there are no proposals to use coal at this station). U.S. coal could be displaced if the same volume of gas could be purchased at less than $1.50/mmBtu. As will be discussed later, volume gas is available in the $2.50 to $2.70 range on a short term (e.g. twelve month) or less contract basis. Costs could possibly be reduced to the low $2.00/mmBtu range if longer-term gas acquisition options were pursued.(31) Furthermore, U.S. estimates suggest the value of eliminating acid-gas emissions is approximately $.50/mmBtu. If it were deemed desirable to cut emissions even further below legislated limits, the economic price of natural gas could be increased by $.50/mmBtu. The recent elimination of emission banking provisions was a step in this direction, reducing the margin for error.

These numbers suggest that natural gas is certainly within an economic range for use at the Hearn station, but there are obstacles which would have to be overcome, including, penalties in existing coal contracts, transmission constraints and displacement of production elsewhere in the Hydro system.

Lambton station has a 25 per cent plus forecast capacity factor for the next three years and could be hooked up to gas for less than $1 million within a two-year lead time. CES 87-2 Revised, forecasts steadily declining capacity factors for this station to 1992; however, circumstances may change. Costs of converting the station to gas would have to be determined. The Nanticoke station is expected to maintain a relatively high capacity factor through 1992. Nanticoke is the only station where Western Canadian coal can be blended with U.S. coal. The cost of hooking up to gas is approximately $18 million at this station. Costs of converting the station to burn gas would have to be determined. Ultimately, the benefits and costs of gas use at these locations would depend on planned station outputs, required gas volumes, the gas price, conversion and hook up costs, and other factors.

If reduction of acid gas emissions beyond those forecast by Hydro, or economic support to western gas markets, were judged to be of value, and problems connected with existing coal contracts could be overcome, then the short term gas options could be expanded, including consideration of a private sector combined-cycle service to Hearn. This is also true if demand for electricity is stronger than anticipated or other supply options fail to live up to expectations. Gas options, with the exception of supply to Hearn, will require at least two years to bring fuel supplies on stream.

Longer-Term Options (Beyond 1990)

Looking to the longer-term, the U.S. Electric Power Research Institute (EPRI) has concluded,

> *"...the uncertainties in the utility operating climate have become so great that there is a risk that long-term advantages may never be achieved."*(32)

Alternative technologies should nevertheless be examined for both their short- and long-term effects. The possibility of securing natural gas over the next two to three years at competitive prices under long-term acquisition arrangements should signal to Ontario Hydro the need to re-evaluate gas options. Hydro has indicated that it has begun to do so, but has not been specific.

Gas options over the longer term can be cast in a scenario in which emission standards constrain coal-fired capacity and coal options require new, cleaner technologies. There are many uncertainties with respect to future coal options, including technology, coal prices and public reaction to the building of new coal-fired generation facilities (the latter concern may be mitigated if clean burn can be obtained).

Coal Technologies

A study of coal combustion technologies by Stone & Webster for the Ministry of Energy has concluded that suitable technologies will be available in the future with costs favourable to the cost of flue-gas cleanup. (33) It points out there is no general, system-wide solution, and that site-by-site analysis would be required to determine which particular coal technologies could be applied in specific situations. The study notes that burning low sulphur coal does not remove the need for installing scrubbers. It also sees no advantage to Hydro in extended pre-combustion cleaning. On the negative side, the study describes a number of limitations of post-combustion coal treatment, particularly in plant performance, waste disposal requirements and the possibility of emission of finer and potentially harmful particles. Nonetheless, the study states:

> *"Technological improvements offer for the first time the prospects of generating clean electric power with minimal emissions."* (34)

The study identifies retrofit and repowering as offering better opportunities than construction of new plant, but identifies a lack of experience in this area. It determines that costing and ranking of coal-fired technologies at this juncture is imprecise:

> *"In a majority of cases only ranges of costs are possible, ranges which are so broad that differences between competing technologies are merged, with ranking difficult."* (35)

EPRI has also rated coal technologies by their state of readiness, as shown in Table 10.

Table 10

THE STATE OF THE ART IN COAL TECHNOLOGIES

Technology	State of the Art
With wet limestone flue gas desulphurization	mature
With regenerable flue gas desulphurization	demo
Advanced pulverized coal with flue gas desulphurization	demo
Atmospheric fluidized bed combustion	pilot
Pressurized fluid bed combustion combined cycle	lab
--with turbocharged boiler	lab
Gasification-combined cycle current turbine	demo/pilot
Gasification-combined cycle advanced turbine	pilot
Slagging gasification-combined cycle--advanced turbine	pilot
KRW gasification-combined cycle	lab/pilot
Gasification-fuel cell combined cycle	lab/pilot
Gasification combined cycle-methanol co-product	pilot
Solid solvent refined coal	demo

Source: Electric Power Research Institute.

There is clearly much research, development and demonstration activity underway in the coal technology area, activity being promoted by the U.S. in its battle against acid rain. It is also apparent that much work still needs to be done to prove some of these technologies in commercial-scale applications. In this respect, cost estimates for many coal options may, as Stone & Webster have indicated, be unreliable. Hydro, in its DSOS study, has included a range of Atmospheric Fluidized Bed Combustion (AFBC) and Pressurized Fluid Bed Combustion (PFBC) coal-fired options and calculated the standard costs for each. These options are at the laboratory research or pilot stage and the cost estimates must be questioned. Hydro notes in the DSOS that AFBC is still in the developmental stage and that the integrated-coal gasification and combined-cycle technologies are at the level of demonstration.

The findings of the Stone and Webster study and the evaluation of EPRI, suggest a danger that Hydro planners may eliminate prematurely real options on the basis of lower "ghost" costs of yet-to-be-proven coal alternatives.

In terms of longer-term strategy, the probabilities are that since RD&D for a variety of new coal technologies is being actively pursued, coal will be an important fuel for Ontario Hydro for decades to come. It would seem that it is the timing rather than the availability of the new technologies which is the issue.

A Strategic Bridging Role For Natural Gas

During the period up to the year 2005, Ontario Hydro could face substantially increased demand for fossil-fired capacity which it may not be able to meet fully within acid-gas emission limits. If new capacity decisions are delayed, for example because of the pace of technology development, higher than anticipated costs, or difficulties in negotiating economic purchases with other provinces or public resistance occur, natural gas could play a strategic bridging role. Strategic-

ally, the opportunity for arranging long-term supplies of natural gas may be most attractive in the next year or two. Thus, it is important that the gas options be subject to fairly speedy review with a view to evaluating their potential contribution to longer-term electricity supply flexibility and security.

Retrofitting and repowering of existing fossil-fired plants would be a major possible application of natural gas in this bridging role. The American Gas Association estimates that repowering is cheaper than new coal-fired capacity e.g. 3.7-3.9 cents/kWh vs. 6.2 cents/kWh. While gas as a fuel is more expensive than coal, the capital costs of a gas option are much lower, operating and maintenance costs are reduced and plant efficiency is higher.(36) A commitment to some level of dual- or multi-firing capability, could put Hydro in the position where it could utilize gas and coal to economic advantage and improve fuel supply security.

Using natural gas for ignition, warm-up, load carrying and select use in coal furnaces can reduce acid-gas emissions. U.S. emissions are highest in the summer months and laboratory work at the Massachusetts Institute of Technology suggests that selecting the proportions of gas and coal burn at specific times of the year may cut emissions and reduce what is potentially a serious sludge disposal problem.(37) Pipeline capacity is also more available during off-peak periods.

A number of U.S. power utilities are now operating on a select use basis. Co--firing with gas can be of extra benefit where coal has to "load cycle" between base and peak and can be of advantage even in the absence of the need for emission control, as indicated in a U.S. Gas Research Institute study of 22 case histories:

> *"...addition of a gas co-firing capability also introduces a wide range of potential operational benefits in addition to SO2 reduction. These operational benefits, when considered economically, reduce the real cost differential between gas and coal and should be considered by the utility in evaluating gas as an SO2 control alternative."*(38)

According to a spokesman for the Consolidated Natural Gas Company,(39) the technological advantages of co-firing are four-fold:

- o improved combustion;
- o flexibility and operational efficiency;
- o reduced emissions and scope for use of a wider range of coals; and,
- o low capital costs with virtually no technology risk.

U.S. experience suggests the percentage of gas co-fired can range anywhere from 5 to 40 per cent, and that full conversion to co-fire can cost less than $3 per kW of capacity for large plants, compared with over $100 per kW for other methods. With respect to acid-gas emission reduction, Consolidated Gas' spokesman states:

> *"There are no lower cost options."*(40)

Table 11

COMPARISON OF COAL-FIRED GENERATION VERSUS GAS-FIRED COMBINED CYCLE
(240 MW)

	Coal-Fired Steam Plant	Gas-Fired Combined Cycle
Operating Characteristics:		
Unit Efficiency (%)	34	43
Heat Rate (Btu/kWh)	10,000	8,000
Economic Parameters:		
Installed Capital Cost (1985$/kW)	1,700	500
Operation & Maintenance-		
Total (mills/kWh)	8.5	2.7
--fixed ($/kW/yr)	19.0	6.5
--variable (mills/kWh)	5.2	2.6
Air Pollutant Emissions: (tons/yr)		
Sulfur Dioxide	4,123	3
Particulate Matter	206	9
Nitrogen Oxides	2,385	1,352
Other Pollutant Emissions: (thousands of tons/yr)		
Sludge	168	0
Ash	60	0
Treated Water Consumption (millions of gallons/yr)	30	15

Source: American Gas Association, "Natural Gas for Efficient Electric Generation".

Table 11 summarizes the relative economics (not including fuel costs) and the relative degree of environmental effects of coal-fired and gas-fired generation for a 240 MW plant. The data suggests that with competitively priced gas, the economics of gas-fired combined cycle plant can be attractive and the environmental benefits of combined cycle plant are particularly striking.

To sum up this section, the use of natural gas for generating electric power is economic and growing in the United States. There appears to be substantial scope for gas-fired parallel generation in Ontario and for use of natural gas by Ontario Hydro, particularly in a strategic bridging role. Ontario Hydro, using a standard cost methodology and assumptions based on pre-deregulation gas markets, eliminated most gas options from consideration in its DSOS evaluation of demand/supply options. Hydro's strategy was to use gas in short-duration peaking only, if at all, when all other options have been exhausted. The rationale for this rested principally on the assumption that natural gas was, and would continue to be, a high-priced, premium fuel. Today, changing gas markets provide the opportunity to Hydro and other power producers and users to re-evaluate the role of natural gas. Our examination of the evidence available from various sources and interviews suggests that gas options are open which could be economic and environmentally attractive. Once again, the gas options are:

- o new combined cycle powerplants. These plants have short lead times and costs can be competitive if gas supply is contracted for on a longer term basis. These plants offer a clean, efficient and reliable source of electric power. They can also be modular in design and be either expanded or mothballed incrementally to meet changing power needs. They reduce some of the cost risks associated with major power construction projects. More-

over, they can be run privately or by Hydro.

- o Repowering with natural gas for existing fossil-fired capacity. As generating equipment ages, efficiency and reliability are reduced. Combined cycle repowering can take three forms: (i) peaking turbine repowering; heat recovery repowering; and, (iii) boiler repowering.

- o Select use of gas for existing and new generating units. The two main forms of select use are the *co-firing* of gas with coal and *seasonal use* of gas to control acid gas emissions. In these uses, gas can enhance boiler performance, lower maintenance costs and cut breakdowns. Co-firing with gas also can provide cleaner and quicker startups and insurance against disruption of coal supplies and tightening of emission standards.

- o cogeneration. Interest in this area is increasing and the potential is high.

The particular application of these technologies will vary site-by-site and with overall electric power requirements, which also vary by region in the province.

The following section examines the availability and cost of natural gas and options for purchase.

3. THE AVAILABILITY AND COST OF NATURAL GAS

In assessing the potential for the use of natural gas in the production of electric power it is vital to consider the availability of natural gas as a fuel to Ontario Hydro and parallel generators. Long-term supplies of natural gas at prices competitive with other fuels is a prerequisite if gas is to play a significant role in the generation of electricity. Three factors are pre-eminent:

- o the long-run reserves of natural gas;
- o the deliverability of gas to the electricity generator; and,
- o purchase options and costs.

3.1 CANADA'S NATURAL GAS RESERVES

The National Energy Board (NEB) states that conventional natural gas supplies from western Canada are capable of meeting domestic and export demands at least until the year 2000. (41) At the end of 1984, 96 exajoules of reserves were estimated --79 in conventional areas and 18 in the frontier. Anticipated reserve additions from conventional areas over the 1985-2005 period range from 20 to 37 exajoules, depending upon the market price of natural gas. The ultimate potential of the Western Canada sedimentary basin is estimated at between 170 and 200 exajoules, of which 133 exajoules had been discovered by the end of 1984. The Canada Oil and Gas Lands Administration (COGLA) has estimated frontier discovered reserves to be in the range of 36 exajoules. Western Gas Marketing Limited estimates that at the 1985 production level, the reserve life of conventional gas resources is 33 years, and without exports to the U.S., 41 years.

Canada's natural gas reserves estimated in 1984 and productive capacity to the year 2000 are shown in Table 12.

Productive capacity of natural gas is forecast to decline over the 1985-2005 period, with a more rapid decline in the low-price scenario than in the high. The NEB emphasizes that if natural gas prices turn out to be higher than assumed in the high-price scenario, increased supplies could occur. Even so, annual reserve additions are projected to be *"much lower in the future than in the past."* (42) Exports are expected to maintain or improve moderately their share of the U.S. market. The NEB concludes:

> *"Evergreening of existing export authorizations and/or expectations of future export licences of a significant nature will likely need to be supported by gas reserves outside the conventional producing area."* (43)

and,

> *"It is quite clear that frontier supplies will be required early in the next century to satisfy projected domestic requirements."* (44)

The outlook for Canadian natural gas exports is unclear. The American Gas Association appears to have taken a more sanguine view of U.S. domestic gas supply:

> *"The U.S. does not have a problem as regards domestic gas supply resources...conventional lower 48 states' gas resources...(are) equivalent to roughly a 50 year supply at current consumption levels...in the period 1981-1985 aggregate reserve additions were 93% of production...various unconventional reserves will add several hundred years to our supply base."* (45)

Canadian natural gas supply and demand projections for conventional areas are shown in Chart 6.

Table 11

NATURAL GAS RESERVES AND PRODUCTIVE CAPACITY
CANADA
(Exajoules)

Natural Gas Reserves:	1984
Conventional	
Initial reserves	133
Cumulative production	-54
Remaining reserves	79
Frontier	18
Total estimated reserves	97

Productive Capacity:	1985-2005	
	High Price Case	Low Price Case
From		
Established reserves	62	59
Reserve additions	16	12
Total conventional	77	71
Frontier	5	0
Total productive capacity	82	71
Estimated Demand	67	72
Excess capacity	15	-1

Source: National Energy Board.
The high price gas assumes $US27.00 per barrel oil and the low price case $US18.00.

3.2 PIPELINE CAPACITY

Natural gas reserves are adequate to supply growing needs over the next decade and beyond. Pipeline capacity would have to be expanded to carry large incremental volumes of gas. The TCPL system has an overall capability to deliver maximum throughput of 4.5 bcf/day. This translates into 1,642 bcf or 1,728 PJ per year. In 1985, TCPL delivered 1.2 tcf of natural gas, which amounts to approximately 73 per cent of capacity. Field gate availability is estimated at 5.6bcf per day or 2,032 bcf per year.

In assessing pipeline capacity it is important to keep in mind that capacity is expanded incrementally and relatively quickly by looping and adding compression stations. The TCPL 2,500 mile long pipeline is in reality a 6,600 miles long system looped up to four times in parallel lines. Along the system are compressor stations about every 50 miles with a total power rating of 1.4 million horsepower. Capacity is expanded to meet new demands by adding sections or "loops" of pipe and compressors.

Gas users purchasing major new volumes would negotiate transmission tariffs which would account for pipeline capital and operating costs. Spokesmen of the pipeline industry state that adding capacity to meet large peak gas volumes would not be economic, but that other demands could be met and would be assessed on a case-by-case basis. It would be wrong to assume that pipeline capacity is inadequate to meet future, growing needs.

We are advised that the transmission/delivery system is secure: TCPL has never failed to deliver gas to firm customers. It is highly unlikely the pipeline companies or local natural gas utilities would make contractual obligations for gas delivery which they could not meet. TCPL buys approximately one half of all the gas produced in Alberta and has under contract approximately 42 per cent of Alberta's remaining marketable reserves. The Company's 1984 reserve life index stood at 24 years.

3.3 NATURAL GAS PURCHASE OPTIONS

Options for natural gas purchase by Ontario Hydro and parallel generators include:

(i) negotiating supply with local distributors or TCPL;
(ii) direct purchase of natural gas from producers and arranging transportation and delivery with TCPL and the distributors;
(iii) outright purchase and ownership of uncontracted gas reserves and arranging shipment; and,
(iv) development of an oil and gas exploration program to meet specific supply needs.

Some elaboration of these options is necessary.

Purchase of gas from local distributors or TCPL is obviously recommended by the pipeline and distribution companies. The major advantage claimed is security of supply. Through pooling of a multitude of interconnected gas reserves, delivery of firm supplies of gas can be guaranteed. "System gas" as it is sometimes called, is also known as "premium gas" because it includes many of the productive reserves. In the short term system gas may be more expensive, but it is arguable whether or not this would be the case over the longer term. For example, gas users opting for non-system gas could face delivery problems and have to buy expensive back-up supplies or supply insurance.

Major gas users, more than the smaller, have both the capacity and the incentive to evaluate the relative benefits of other options over system gas. On the other hand, assessing and planning for major incremental demands for natural gas would obviously require the cooperation of TCPL and the local gas utilities.

Indications are that large volume gas is available in the $3 mcf or lower range for periods ranging up to 20 years. TCPL is to supply 50 MMCFD to the Ocean State Power project at Rhode Island on a twenty year term. The base price of the gas is in the US$3.00 range, with an annual escalator based on a fossil fuel index. The price has a monthly demand charge and commodity charge component. The proponents claim the project is viable down to an oil price of US$10.00 per barrel. This is a 460 MW base-load combined-cycle plant operating at an 80 per cent or better load factor. It is planned to be completed in two 230 MW stages.(46) Similar or higher volumes to Ontario Hydro would be cheaper. Spot prices of delivered gas in the Ontario market are in the range of $2.50-$2.70 per mcf.

Direct purchase, where a gas user buys gas directly from producers, is becoming more common. Contracts tend to be short term in a highly price-competitive market. Regulatory issues connected with direct purchase are still under review, including by-pass. Major gas users have found direct purchase attractive and appear to be taking advantage of low spot prices on mainly one year terms. Interest is rising in 2-3 year direct purchase arrangements.

Purchase of uncontracted gas reserves is yet another option offering scope to major gas users. A study conducted for the Ministry of Energy by Liddle Engineering Ltd.,(47) estimates there are 8.3 tcf of uncontracted reserves in Alberta, equivalent to 1/3 of TCPL's contracted reserves (which is consistent with a TCPL estimate that it had 27 tcf of remaining reserves under contract at the end of 1985). Approximately 2.5 tcf of the uncontracted reserves are rated as "most accessible" and alone equivalent to 35-45% of Ontario's present annual total consumption. Moderately accessible reserves total 3.4 tcf and the least accessible 2.4 tcf.

The Liddle study concludes that uncontracted gas supplies are very large in a Canadian and Ontario context. Moreover, the study also addresses the issue of direct purchase and concludes that direct sales should increase the overall security of supply, even though individual direct sales will be less secure and

backstop supply expensive. Issues connected with transportation of the gas would have to be addressed; however, recent Ontario Energy Board recommendations are designed to provide flexibility and to distribute costs fairly on the basis of use.

Translating the Liddle Engineering uncontracted reserve numbers into volumes of gas available to interested purchases is difficult. Assembling reserve pools may involve dickering with many owners, each of whom may have a unique perspective of prospects for future energy prices and varying encumbrances in the form of secured bank debt and other liabilities.

For companies contemplating longer-term gas purchases, price security is an issue. A strategic option is available to provide price protection. Individual major gas users, or groups of users, could explore for and develop their own gas supplies. By linking upstream E&D with locked-in downstream markets, such gas users could potentially hedge long-term gas prices more securely. E&D risks are evident; however, risks can be evaluated on the basis of the historical drilling success and other factors. Market risk is minimized in that the gas producer (the gas user in this case) has the option of using the gas in production or selling it, depending upon production requirements and gas market conditions. One estimate suggests that up to 90cents in profit could be used as an offset to a Toronto City Gate gas price of $3.36. [48] If this is in the ball park, then E&D could be a low cost gas option, producing a base gas price in the low $2 range.

None of the above options need be exclusive for large gas users. For example, a user such as Ontario Hydro, which may require modest volumes of gas initially, but substantial volumes in 3,5 or 7 years and beyond, could do a short-term direct purchase, buy uncontracted reserves for the medium term while prices are low, and undertake an exploration and development program to supply longer-term gas and hedge the price. A typical E&D program would bring gas on stream in 5 years. Note also that volumes of "system gas" could be blended with non-system gas to satisfy specific supply security concerns.

An oil and natural gas exploration program for Ontario Hydro would be analogous to Hydro's current involvement in coal mining. Hydro has indicated a strong reluctance to enter into new long-term contractual arrangements for fuels; however, it may have little choice in the matter as time goes by.

To sum up on availability, gas reserves are adequate to meet fairly substantial and incremental gas demands. Transmission and distribution facilities can be added to on an as required basis. A range of options are open to gas users to secure supply and contain costs.

The following section examines barriers to the use of natural gas in electricity generation, barriers which will have to be addressed if the options are to be put to the test of the marketplace.

4. BARRIERS TO THE USE OF NATURAL GAS IN GENERATING ELECTRICITY

Based on our analysis and the results of interviews, it is apparent that barriers --real or imagined--exist to the use of natural gas in electric power generation. These barriers are:

- Ontario Hydro's perception of its economic role and the place of natural gas;
- lack of information and communications between natural gas suppliers and users on the opportunities for using this fuel;
- insufficient appreciation for the facts on the availability of natural gas, the options for purchase, and the possibility of hedging costs over the longer-term; and,
- the incomprehensibility of Hydro's "standard cost" option pricing and ranking methodology.

Some persons we interviewed suggested the lack of a Government policy on the use of gas in electricity generation was also a barrier. Government policy, in general terms, is to encourage the use of that fuel mix which is the most cost-effective and has minimal environmental impact. Judged on these grounds, there is no policy barrier to the use of natural gas to produce electricity in Ontario. Perhaps a reiteration of the Government's position would be helpful to the interested public.

Brief commentary is now made on each of the above barriers.

4.1 HYDRO'S ECONOMIC FUNCTION

Hydro believes that,

> *"...natural gas is likely to be a premium fuel with higher value added, and it is unlikely that government policy would permit a large use for the fuelling of generating stations."*(49)

Moreover, Hydro observes,

> *"...the provincial economy impacts of fossil projects tend to be poor."*(50)

The economic leakage into "imported fuels" is identified by Hydro as the primary reason for the poor provincial economic impact of fossil-fueled projects, and the Corporation has completed an analysis of the economy-wide impacts of the various DSOS options. This study shows that the Ontario GDP and employment impacts are higher for nuclear plants, high-load factor conservation and cogeneration using fuels indigenous to Ontario. Conversely, projects using imported fuels--oil, natural gas and coal--have a lower economic impact in the province. Not surprisingly, the economic stimuli of the various options are inversely related to their "standard costs".

From Hydro's perspective, development of energy resources indigenous to Ontario appears to have priority:

> *"There will still be concern for the provincial economy, job creations etc. and this must be expected to have some impact on planning decisions."*(51)

Past Government of Ontario fiscal and economic policies have probably encouraged Hydro in this line of thinking. On occasion, the Government of the day has required Hydro to adjust its capital construction cycle for economic stabilization. More importantly, the 1980 BILD program promoted electric power as an engine of economic development over the longer term. In the context of the present Government's policy of cost effectiveness and minimal environmental impact, spin-offs in the form of indigenous resource development, provincial employment and regional development, while important, are secondary objectives.

The principal argument against Hydro's position is that it takes a parochial provincial view of economic benefits whereas, in the case of natural gas and Canadian coal, a Canadian focus would perhaps be more appropriate. This is a political question. Furthermore, the Hydro analysis fails to capture the dynamics of the various options in terms of the advantages some may have in timing, flexibility, technological feasibility, public acceptability and other factors.

Clearly, Hydro feels it has some special responsibility to pursue supply options with higher Ontario valued added. There can be conflict between this objective and that of producing energy at the lowest average long run cost. Moreover, such an energy fuel policy could be construed as a non-tariff barrier to interprovincial trade. We wish to stress, however, that to this point in time, and to the best of our knowledge, natural gas has not been treated discriminately by Ontario.

4.2 INFORMATION AND COMMUNICATIONS

Interviews with the gas industry and Hydro indicate to us a considerable information gap and problems in communications. For example, at the time we interviewed Hydro staff our impression was that they were not aware of the full range of gas options potentially available to the Corporation or of the major impact de-regulation was having in the natural gas market place. Hydro, of course, isn't in the gas business. Nevertheless, more and better information on gas markets is necessary for Hydro to evaluate fully the gas options, in our opinion.

For their part, companies in the Ontario natural gas industry are, with some exceptions, only now beginning to explore possibilities of greater use of natural gas by Hydro and parallel generators. (For example, earlier this year a committee of the Ontario Natural Gas Association (ONGA) was formed to examine the potential for co-generation). The natural gas industry lacks information about electrical system demands and loads, site conversion costs and problems etc. which would be helpful in making proposals to Hydro. It should be possible for the industry to obtain more specific information without impinging on Hydro's corporate confidentiality requirement.

Meetings are occurring between Hydro and the natural gas utilities and with potential parallel electricity generators. From comments made at confidential interviews it appears there are some staff at Hydro who doubt that gas can compete under any circumstances, and that some gas industry personnel doubt that Hydro will take gas seriously even if it can be shown to be competitive. For instance, it was suggested to us by some in the gas industry that Hydro will discuss gas options, but only those which involve big volumes of gas for short-duration peaking i.e. the most expensive gas options. From Hydro's side, we were advised in one meeting that coal suppliers would out-compete any natural gas proposals.

Insofar as parallel generation is concerned, apart from a few selected cases, we must assume that most industrial and commercial operations are not aware of the possible advantages.

4.3 HYDRO'S STANDARD COST METHODOLOGY

One unfortunate aspect of communications is the incomprehensibility of Hydro's standard cost methodology. Development of the DSOS study based on this approach, was "a major corporate wide effort", to rank the options on a consistent basis. Time does not permit a detailed review of this technique; however, several observations are in order.

First, of the persons we contacted, including Hydro employees, only Hydro's System Planning Division staff--the persons responsible for the DSOS--claimed to understand the standard cost approach and warranted its validity. To outsiders, and others within Hydro, the study methodology is, to use a well-worn phrase, "an enigma wrapped in a mystery".

Second, and of importance to our examination of the potential for natural gas use in electricity generation, the study's standard cost results and associated assumptions and focus on the long term may have unnecessarily limited consideration of the gas-fueling options. The DSOS is based on 1985, 1984 and perhaps earlier data. Natural gas market conditions and forecasts are dramatically different today. We are advised that the DSOS analysis has not been updated to reflect more current natural gas markets and that phase two of the DSOS does not consider gas options.

As a vehicle for communicating the Corporation's concerns and options for the future and stimulating focused debate the standard cost approach may be simply a failure.

5. STRATEGIC ISSUES

There are a number of strategic issues to be considered in evaluating the natural gas options for producing electricity. The following are probably among the most important:

- is the cost and security of Ontario's electricity supply vulnerable to lags in development of clean-coal technologies and delays in approvals for alternative supply options?

- natural gas is an "imported" energy resource. Is it to have free competitive access to the Ontario market in substantial volumes for purposes of generating electricity?

- if substantial, long term gas volumes were to be required for electricity production, what would be the implications for the "reserve test" and for gas exports, and what might be the attitude of Western producers and the Alberta government?

- would gas producers and the Government of Alberta be concerned that Ontario could lock up substantial incremental future supplies at prices lower than what might be available in the export market?

- if Ontario were in the future to argue for control of the domestic gas price would Alberta react by withholding removal permits and jeopardize Ontario's electricity production?

- how might the West react if western gas is substituted for western coal?

- should economic gas-fired parallel generation be more aggressively encouraged and, if so, what roles, should Hydro, the municipal electric utilities, the Government, the Ontario Energy Board and others play?

- is there economic/political value to reducing acid-gas emissions even further below legislated limits?

6. POLICY IMPLICATIONS

If it can be demonstrated to the Government's satisfaction that natural gas is a competitive fuel for electricity generation over the longer-term which may have strategic advantages, the necessary policy requirements can be spelled out in fairly simple terms:

1. Clarification for Ontario Hydro of the Government's approach to the use of natural gas.

2. A requirement that Hydro investigate and report on the gas-fired combined-cycle and repowering opportunities, with recommendations.

3. Development of a cogeneration policy with the following elements:

    - o buy-back rates based on avoided costs, possibly with rates varying by region.

    - o education and communications programs.

    and, if necessary:

    - o clarification of the roles and responsibilities of the various players.

    - o a process and procedures for project review/approval.

    - o an incentives program.

- specific annual MW targets, which could be put up to bid.

- a committee or board to oversee the development of cogeneration.

There are three broad policy options for the Government to consider with respect to the future role of natural gas in producing electricity:

- the status quo;
- an advocacy role; and,
- a mandate role.

The status quo policy option allows Ontario Hydro to determine the extent of natural gas use for purposes of electricity generation by both itself and private generators. In reality, Hydro will anyway play an important role. The issue is whether or not Hydro should control the process.

An advocacy role for the Government would see the Ministry of Energy playing the role of broker, providing essential information and education and bringing together gas suppliers and electricity generators. A coordinating mechanism and education program would be required.

A mandate role for the Government would see the Ministry of Energy stating a positive policy with respect to natural gas usage in electricity generation and establishing explicit criteria and programs (and legislation) to overcome institutional and other barriers. Such a policy position might include a parallel-generation strategy with multi-year targets and favourable buy-back rates. A coordinating mechanism would be required.

A co-generation policy comprised of buy-back rates which reflect costs Ontario Hydro can avoid and education and communications programs may be all that are required to stimulate a greater level of co-generation activity. However, if the Government is concerned that the barriers noted earlier could delay unduly co-generation development, and sees value in moving relatively quickly to take advantage of current favourable gas markets, then a committee or board could be established to help move things along. This organization could, for example, propose annual co-generation targets based on discussions with the various parties, recommend incentives and possibly be a vehicle for the review and approval of projects to meet the pre-determined targets. With such an approach, some clarification of roles and responsibilities would be required. For example, would Ontario Hydro have the final say on proposals, or would the Corporation be required to accept proposals approved by the committee/board? Would the Ministry of Energy be represented on the committee/board? How would the committee/board relate to the Ontario Energy Board? What role would the OEB play? Could the OEB in fact take on the co-generation promotion role?

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TECHNICAL TERMS

There are many technical terms in this paper, some of which will be familiar to readers working in various areas of the energy field. However, given the focus of this study, definition of a limited number of terms used may be helpful.

Cogeneration is the sequential production of electrical or mechanical energy and thermal energy from a single source with an overall improvement in energy conversion efficiency. For example, steam from a boiler is passed through a turbine to produce electricity before being used in the production process. Normally wasted exhaust heat can also be captured and used partially to drive a second turbine for thermal or electric energy production.

Combined cycle repowering refers to the integration of new and used equipment at an existing site, with the final equipment configuration resembling a new gas-fired combined cycle unit.

Peaking turbine repowering refers to the addition of a steam turbine and heat recovery unit to an existing gas turbine, with the efficiency improvement allowing the unit to convert from peaking to baseload operation.

Heat recovery repowering is the replacement of an old coal boiler with a gas turbine and heat recovery unit, leaving the existing steam turbine in place.

Boiler repowering refers to the addition of a new gas turbine from which the exhaust gases are fed into an existing coal boiler, replacing forced draft fans and air heaters.

Co-firing is the burning of small amounts of natural gas in a coal boiler at the same time as coal is being burned. It is related to the "select use" concept. Typical co-firing installations introduce natural gas into or alongside the combustible jets of coal that go into the boilers.

Select use is the co-firing of small amounts of natural gas with coal, with the proportions of the two fuels being varied over the seasons to minimize emissions.

Net capability (as used in the Ontario Hydro CES) is a measure of the output from the station if it were required to run flat out over the year, expressed as a percentage of the designed capability. Net capability is lower than designed capability because of such factors as outages and derating.

Net capacity (as used in the Ontario Hydro CES) is a measure of the the planned output from the station measured relative to designed capacity.

Base load capacity refers to the capacity of electricity generating equipment which operates over most hours of the year.

Available electrical capacity is the sum of installed capacity plus firm purchases of power.

Established (oil and gas) reserves are those reserves recoverable under current technologies and present and assumed future economic conditions, proved specifically by drilling, testing or production, plus that judgment portion of contiguous recoverable reserves that is interpreted to exist, from geological, geophysical or similar information, with reasonable certainty.

Frontier reserves are those of the northern and offshore areas of Canada.

Productive capacity is the estimated rate at which natural gas and oil can be produced from a well, pool or other entity, unrestricted by demand, and taking into account such things as reservoir characteristics, the availability of gathering, processing and transmission facilities and economic considerations.

CHARTS

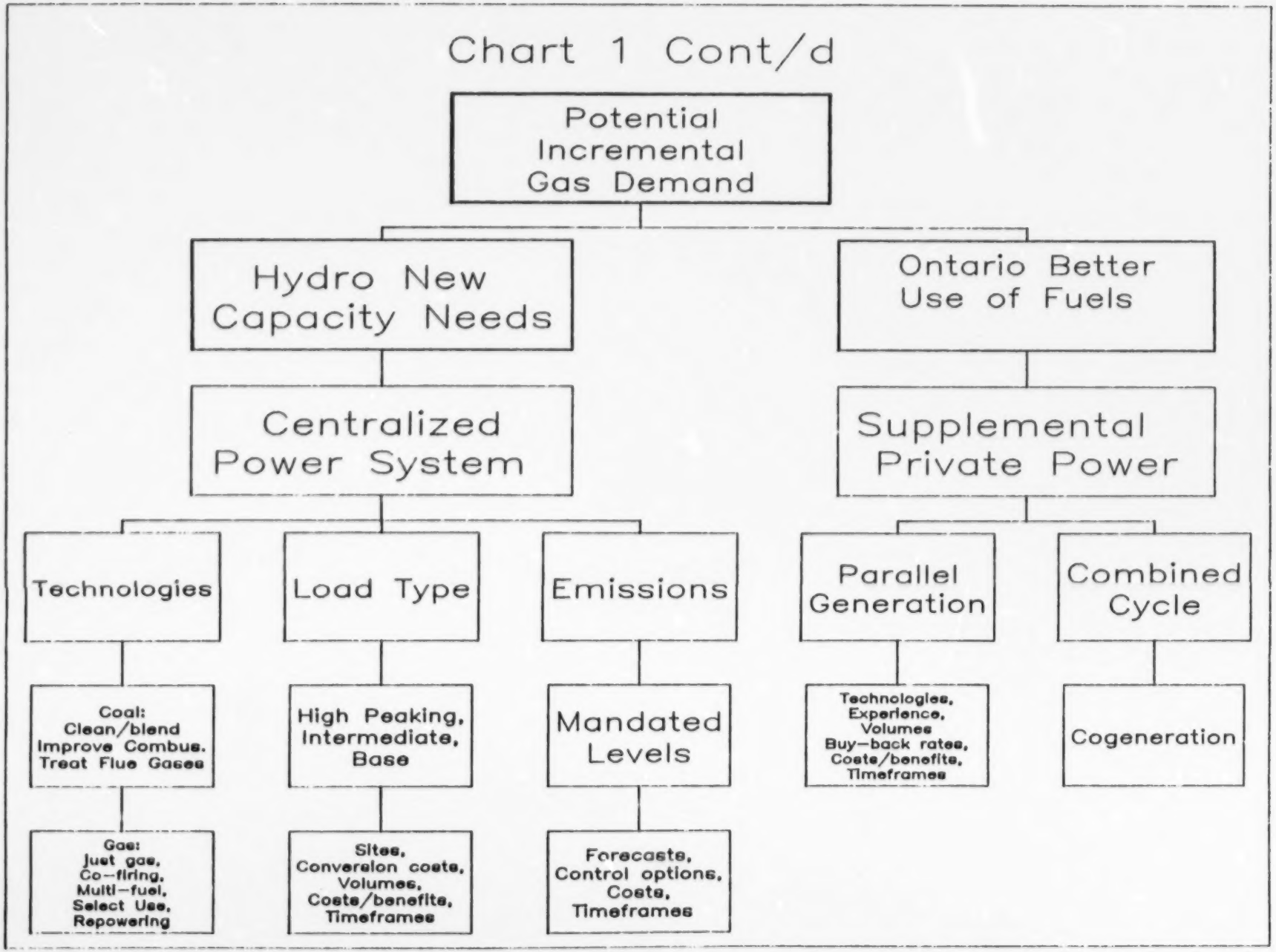
Chart 1 Cont/d
Potential Incremental Gas Demand
Hydro New Capacity Needs
Ontario Better Use of Fuels
Centralized Power System
Supplemental Private Power
Technologies
Load Type
Emissions
Parallel Generation
Combined Cycle
Coal: Clean/blend Improve Combus. Treat Flue Gases
High Peaking, Intermediate, Base
Mandated Levels
Technologies, Experience, Volumes Buy-back rates, Costs/benefits, Timeframes
Cogeneration
Gas: Just gas, Co-firing, Multi-fuel, Select Use, Repowering
Sites, Conversion costs, Volumes, Costs/benefits, Timeframes
Forecasts, Control options, Costs, Timeframes

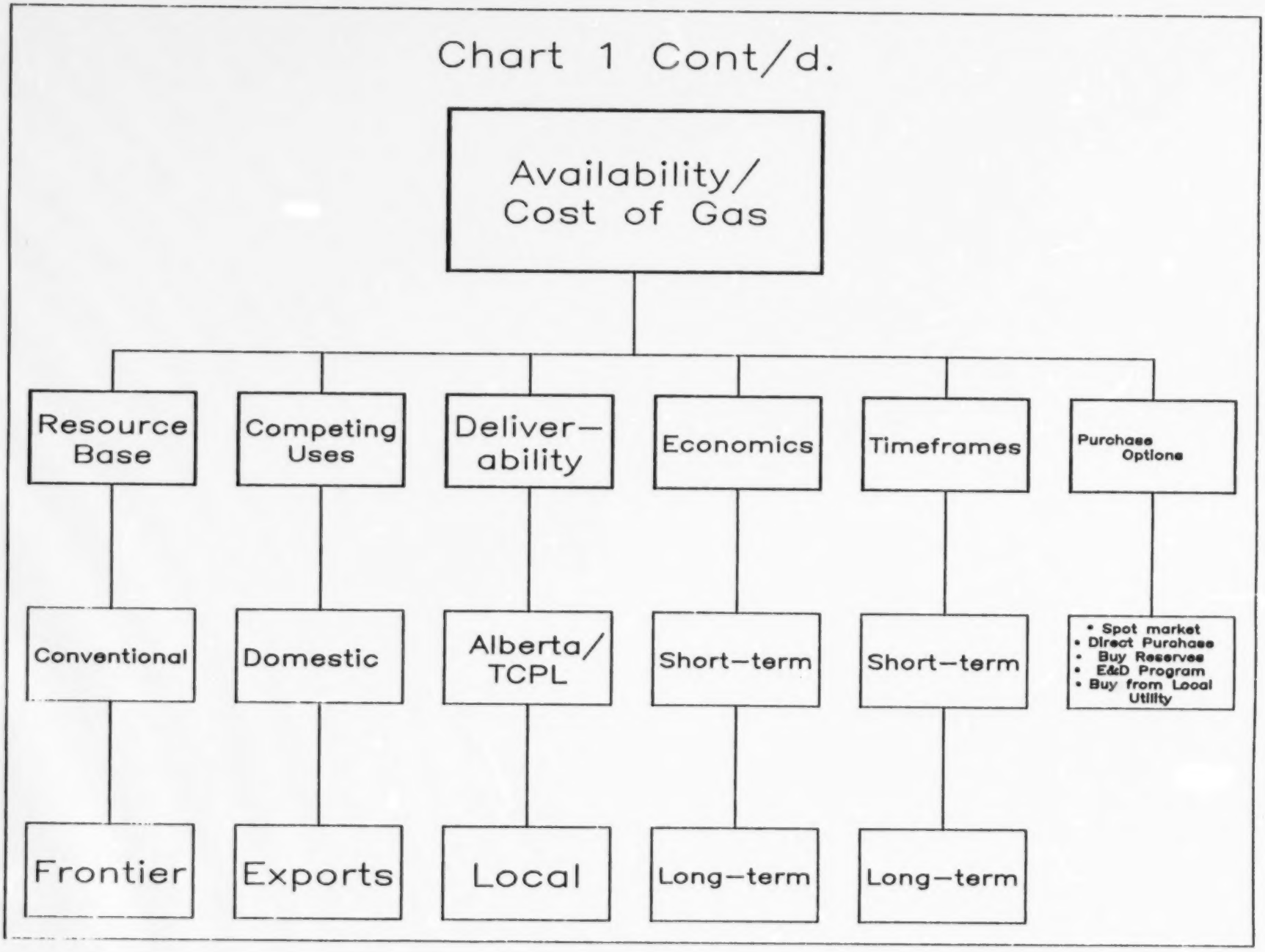
Chart 1 Cont/d.
Availability/ Cost of Gas
Resource Base
Competing Uses
Deliver– ability
Economics
Timeframes
Purchase Options
Conventional
Domestic
Alberta/ TCPL
Short–term
Short–term
• Spot market
• Direct Purchase
• Buy Reserves
• E&D Program
• Buy from Local Utility
Frontier
Exports
Local
Long–term
Long–term